ROY SHANKER JUNE 1, 2023 CIFP-RA

MISSING ELEMENTS IN CAPACITY MARKET PROPOSALS

(These slides were prepared prior to PJM's 5/30 presentation, some of the issues are resolved by PJM's proposed move to an hourly RTO reliability model (If adopted). I will adjust comments as I go)

BACKGROUND

- FOLLOW UP ON GENERIC ISSUES RAISED 10/11/2023 PRE-ELLIOTT AND CIFP https://www2.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20221011/item-02d---perspectives-on-high-level-design-concepts---roy-shanker.ashx
- FOLLOW UP ON QUESTIONS SUBMITTED TO PJM SINCE APPROXIMATELY 3/15/23 THAT REMAIN OPEN https://www.pjm.com/-/media/committees-groups/cifp-ra/postings/cifp-ra-questions-received-by-stakeholders.ashx
- The following represents my own views and questions I have received and not necessarily an advocacy position of any clients or support of any specific proposal. *The goal is to understand and fill in the blanks for allof the proposals or get explanations if necessary.*

PURPOSE OF DISCUSSION

- A number of questions common to all proposals have been raised but in general are unanswered
- Consideration also suggests a few more of these types of generic issues
- Not supporting any specific proposal but want to get issues on the table and make sure every proposal has a way to deal with these items

Three Areas of Concern: The Answers Will Obviously Trigger More

- Representation of stochastic generation and common mode outages in Locational Capacity Resource processes: planning, accreditation, auction planning parameters (FPR/IRM, ELCC, CETO, CETL, Local Reliability Requirements, related demand curves). *How do all the pieces fit together?*
- Role of ”must offer” and its relationship to planning parameters for auction as well as “expected” output and PAI process
- Eliminating CBM/CBT, pricing emergency assistance during PAI related to exports, balancing ratio

Understanding Who Pays When Locational Requirements are Not Properly Modeled/Recognized

- In general, the problems discussed in next section become “hidden” charges to load and bypass any more reasoned cost allocation that might assign costs to generation or different load
- Omissions/limitations in the overall process for locational characteristics ultimately show up as transmission violations/needs
- This leads to new RTEPP projects (per prior discussions with PJM)
- These costs follow Schedule 12 regardless of root cause in failure to meet RPM assumptions, weaknesses in models for reliability planning, accreditation or interconnection

I. Representation of Stochastic Generation/Common Mode Outage in Locational Capacity Resource Processes

- General Practice in PJM (PRISM and Transmission Representation) is to have a single location/copper plate/infinite transmission in Planning Processes. Use thermal equivalent or historic output but no transmission representation. This sets FPR/IRM and VRR Curve.

- So far only very limited discussion of locational/transmission constraints in base reliability proposals (only PJM has commented and only on CETO), there has been a tiny bit on common mode adjustment for EFORd (e.g. incorporating seasonal performance in EFORd), and ***none*** on stochastic representation in power flows or planning models. (E.g. Basic ELCC process is not locational either)

- Locational Tests and Representation in RPM are intended to test/enforce the legitimacy of the initial infinite transmission assumption and set associated locational requirements for transmission and generation

- E.g. 1 in 25 standard for CETO and measurement of CETL is a lesser proxy for the assumed infinite transmission; the Local Reliability Requirement in the Auction is directly tied to CETO and the LDA VRR curve.

- ***Getting these omissions right is key to maintaining reliability and to matching current RPM auction structure to reality when setting prices***

II. In FPR and IRM

- Pool Wide Reliability built on assumed infinite transmission
- While we test for internal transfer capability there is no test for stochastic nature of intermittent generation (ELCC looks at hourly time step but still keeps all load and generation at same point so see some time diversity but not spatial diversity, e.g. where a power flow is needed for analysis use of thermal averages misses the most important information on which units are actually operating and the associated flows)
- Ignoring locational properties and intermittency at the RTO level over states reliability

III. In CETO

- CETO sets transfer target and LDA Reliability Requirement and LDA VRR
- CETO is “consistency target” for assumption of infinite transmission
- Work backward to one aggregate transmission need from rest of PJM (no limit on the rest of RTO) into each LDA to 1 in 25 target
- Again uses thermal equivalent and no consideration of stochastic nature of intermittent generation
- PJM’s proposal will resolve some of this by going to an hourly CETO and use of historic data (still does not see transmission) Likely still too low a CETO target

IV. In CETL

- CETL establishes the transfer constraint into an LDA in the the auction. Reflects actual transmission constraint as PJM sees it and when it binds binds sets the “LDA adder”.
- Key planning parameter for locational representation of price and reliability
- Simple view of test is determining what the level of imports are into an LDA when a transmission violation occurs due to pro rata decreases of “in LDA” generation.
- Uses thermal equivalent in running the test. E.g. a 100 MW wind resource with 15 MW AUCAP will appear as a 15 MW thermal unit that is 100% available in power flow conducted for the test

CETL (Cont. 1)

- No representation of the stochastic nature of intermittent resources, they will always be there 100% of time at derated level. (*No information on how or whether there should be a change reflecting different AUCAP for same unit while power flow is unchanged. This also raised MSOC issues*)
- Totally unrealistic in a power flow context both in quantity and timing of supply, and the resulting pattern of power flow and loadings as different units come on and off in the region (even if the derate on average was correct)
- The higher the intermittent penetration the less meaningful the CETL value and the more overstated the CETL value and *in turn the more actual reliability is also overstated*
- No proposals have addressed this that I am aware of, even as to how the tests would be modified for reduction in AUCAP though power flows would stay the same (*some interaction with interconnection tests as well must also address same issue*) (E.g. how would constraint change as accreditation drops and what is the impact, if any, of a lower AUCAP? How do you do this in the RPM model, whether either average or marginal accreditation?)

CETL (Cont. 2)

- No analysis of how much this will overstate “true” reliability.
- Potentially very materially given concentration of new intermittent resources (e.g. offshore wind) and clustered locations.
- Also , there is a bad interaction with the basic ELCC accreditation not being locational (not clear how to capture this)
- Thus, likely CETL’s are too high and there is less transfer capability and reliability than tests are showing for a thermal equivalent
- NOW THINK BACK TO HOW COSTS GET ALLOCATED FOR NEW TRANSMISSION TO SOLVE THESE INEVITABLE RELIABLITY ISSUES THAT WILL MOST LIKELY SHOW UP IN THE RTEP. (E.G. PAST PJM PROPOSALS WERE TO PUT THESE COSTS IN SCHEDULE 12 FOR EXISTING INTERMITTENTS)

V. Role of ”must offer” and its relationship to planning parameters for auction as well as “expected” output and PAI process

- PJM has a must offer for only some Capacity Resources.
- PJM establishes FPR/IRM assuming all units with CIRs are included in analyses without considering some units may not participate.
- DR, EE, Wind, Solar and Batteries may choose to be Capacity Resources, obtain CIRs as requested/required, but have the option not to offer in the RPM BRA.
- Virtually every planning parameter and auction related values are skewed and “wrong” based on the existence of this option

Must Offer (Cont. 1)

- Obviously FPR/IRM is wrong if it assumes units that don't participate will participate (See SOM comments for magnitude of units with CIRs that do not participate)
- In turn RTO VRR curve is incorrect, again overstating reliability
- Each CETO requires PJM to guess about who will exercise such an option (here reliability impact varies by direction of PJM "forecast error") making the values "wrong" no matter what
- Each CETL is similarly incorrect as beyond intermittent issue, the wrong set of resources will be included in the power flows
- Each LDA VRR and Reliability Requirement is similarly wrong

⌘

Must Offer (Cont.2)

- The preceding makes clear that must offer is a key element and logically the first element in any of the new proposals
- PJM and IMM have suggested mandatory must offer
- To extent any “option not to offer” is retained, the broad impact on all aspects of the BRA and planning parameters requires that such options must be executed before auction elements (FPR/IRM, VRR, CETO, CETL, Reliability Requirements) are calculated
- The full recognition of this issue was not addressed in PJM’s DPL South proposal

VI. Eliminating CBM/CBT, Pricing Emergency Assistance During PAI, Balancing Ratio

- Assumptions about CBM and CBT (in particular) have a material impact on the FPR/IRM and thus the RTO VRR. Assumes free capacity benefit from diversity of parties outside the market
- In a market system, this is an old fashion relic that I have thought should have been removed 25+ years ago. We meet our own needs, sell or buy as possible, but pricing has to consider fixed costs of the seller and the system making the resources available.

CBM/CBT (Cont. 1)

- Someone has to compensate the seller for capacity contribution associated with energy sold/bought during emergencies
- No discussion in CIFP-RA , some by PJM related to Storm Elliott
- Eliminating CBT from FPR/IRM will increase internal demand and ultimately supply at target LOLE/EUE
- General approach should be from perspective of what is the “right” price of emergency assistance in a market world. At minimum compensatory to sellers. The definition of “compensatory” should match the rest of the market design.
- Suggests that during PAI the benefit of continuing sales/exports should be “racheted” in some way to the penalty/bonus rate or BRA price and charged to recipients of power export. Credit (outside of bonus/penalty process) should go to load. Sellers compensated via the adjusted VRR curve.
- This would be an alternative to modifying the B factor as PJM has mentioned. Possibly could be combined but unclear.

⌘ Example: One of the Questions Submitted In March That Integrates Much of the Above And Should Be Addressed by All Proposals

- 9. Hypothetical. Assume NJ adds the proposed 7000 MW(MFO) of off-shore wind. Let's assume it gets 2800 CIR's and is initially accredited for that amount under ELCC (40% marginal). (Also the unit meets all other interconnection standards). Three years later, after 30,000 MW (MFO/nameplate) of wind is added in ComEd, the NJ wind is now given an AUCAP of 1400 (e.g. 20% under a marginal regime). This occurs as ELCC accreditation is not locational

- Summarize for both year 1 and year 4 how the following would be addressed and calculated for the PS LDA (Assume just 1 LDA for the whole state) for the 7000 MW off-shore facilities under the PJM straw Capacity Market proposal presented this week. (If you think it is necessary to have an average value for the ELCC class, explain why and how you would incorporate it into the answers, pick appropriate numbers consistent with the average also declining, but more slowly. I believe that PJM had forecast numbers that included this type of relative data in their ELCC presentations)

- a. Calculation of the NJ LDA CETO, what is the representation of the MW of the off-shore units (the unit) in the CETO calculation? For all these it is both year one and four and an explanation of the process to get the values.

- b. Calculation and representation of the unit in the CETL for the PS LDA in each year

Questions Continued

- c. Calculation and representation of the unit in the Reliability Requirement as part of the Planning Parameters for the BRA in both years.
- d. Calculation and representation of the unit in the baseline for the RTEP in terms of peak power flows.
- e. Calculation and representation of the unit in the determination of CIRs for the interconnection process if different from (d) for a given associated baseline.
- f. Calculation and representation of the unit (e.g. MWs) in determination of the MSOC (i.e. what are the MW assumed for the Net ACR calculation)

Question Continued

- g. Calculation and representation of the unit (e.g. MWs) in determination of MOPR (i.e. what are the MW assumed for the Net ACR calculation)
- h. Calculation and representation of the units day ahead must offer energy requirement.
- i. What would be the “Expected” output of the facility during a PAI for calculating penalty/bonus. (you can assume seasonal difference, but the question is confirm that the expected MWH change as the AUCAP goes from 2800 to 1400, which I am assuming would not happen but want to confirm)
- j. Calculation and representation of the unit in the IRM study and the development of the FPR.
- k. How would the unit be represented for purposes of any ancillary service sales under current rules but with the different AUCAPs.
- L, Would moving to marginal representation change any of the metrics for the supply of ancillary services?